5

Chapter 5 - Fuel Diversity Perspectives

The topic of fuel diversity has been raised frequently in public discussions and meetings related to this project. Fuel diversity is a complex issue and can be viewed in a number of ways. The applicants have stated, in the CPCN application and at several public forums, that maintaining or enhancing the fuel diversity in WEPCO's generation mix is one of the primary reasons they have proposed the ERGS facilities. An examination of the pie charts in Figures 3-1 and 3-4, shows that about 50 percent of WEPCO's generating capacity is presently coal-fired and that about 70 percent of the energy consumed by WEPCO customers is produced by coal-fired generation. From this perspective, the applicants' statements seem to be inconsistent. However, there are many considerations in determining the appropriate mix of generation technologies and fuel sources.

Some of these considerations include: the age and condition of WEPCO's existing generating units; the source and availability of the fuels; fuel prices and the expected stability or volatility of fuel price over time; the overall energy balance and use in Wisconsin; and the environmental effects and safety issues associated with the use of different fuels.

This chapter will discuss some of these issues and perspectives. The chapter does not contain specific conclusions or recommendations with respect to the proposed ERGS project or any of the alternatives to the project. It is included in the EIS to provide information, raise awareness, and generate discussion. Although this chapter is focused on coal power plants versus natural gas-fired facilities, staff recognizes that a similar analysis of an integrated resource alternative which includes renewables, energy efficiency, electric transmission improvements, and possibly other smaller fossil-fueled facilities would also be valuable. Finally, the chapter is organized under the broad topics of reliability, economics, and environmental issues, but issues discussed under one topic often have implications in other areas.

Reliability Issues

Coal sources and availability

There is an estimated 304.6 billion tons of recoverable coal reserves in the United States.[52] The U.S. has about 25 percent of the world's reserves and uses about 25 percent of the worldwide coal used annually. In 2001, the U.S. mined a record 1.12 billion tons of coal, an increase of 60 percent over a 25-year period.

[52] Based on 60 percent recovery rate and US Energy Information Administration coal reserve data.

The current growth trend in coal production began in 1961. From 1986 to 1997, coal production increased by 22 percent, while the number of operating coal mines in the country declined by 59 percent, from 4,424 in 1986 to 1,828 in 1997. Coal prices decreased by 45 percent in real dollar terms over this same time period. Today, roughly equal amounts of Western coal and Appalachian coal are produced with about half as much interior (such as Illinois) coal produced.[53]

Competition from natural gas has slowed the growth of new coal-fired generation capacity but consumption of coal still increased by 28 percent from 1986 through 1997. By 1997, 90 percent of the coal consumed was used to generate electricity. Coal-fired units account for only 5 percent of planned new generation units between 1998 and 2007. But coal-fired net generation capacity is projected to grow because of an anticipated increase in utilization and capacity additions after 2007.

EIA projections between 1997 and 2010, which take into account scheduled generating capacity additions and baseload mix, anticipate nearly a 14 percent increase in annual coal consumption at electricity generators. These projections, and others like them, provide reasonable assurance of long-term coal markets and motivate large companies, especially those with traditional ties to coal, to hold investment positions in coal for the long term.

Natural gas resources, pipeline capacity and storage

Wisconsin has no indigenous supplies of natural gas. Therefore, owners of any natural gas-fired electric generation would have to procure supplies from outside the state. Natural gas is typically purchased from production areas in Louisiana, Oklahoma, and Canada. It is then transported to Wisconsin via interstate pipelines. Some generators connect directly to the interstate pipeline to receive their natural gas. Other generators purchase natural gas from a Wisconsin utility, which means that the gas must also flow through the utility's distribution system to reach the facility. This results in three possible areas for which reliability of natural gas must be assessed: (1) production, (2) interstate transmission, and (3) distribution. Each sector will be addressed separately in this section. The reliability implications associated with the inability of generator operators to store natural gas on-site will also be discussed.

Natural gas production and use: long-term analysis

With respect to production there are two possible reliability issues. First, natural gas must be available in the production region. Second, wells must be in place to make it possible to remove the natural gas from the field. According to the U.S. Energy Information Administration (EIA), technically recoverable reserves of natural gas in the United States in 2001 amounted to 1,614 trillion cubic feet.[54] This is about 82 times the amount of natural gas produced in the U.S. in that year. This is an overly-optimistic perspective of available supplies, however, because the technically recoverable estimate includes, among other items, gas supplies that are not currently economically recoverable. It also includes estimates of natural gas supply volumes that have not yet been discovered.

[53] The US Coal Industry in the 1990's: Low Prices and Record Production by Richard Bonskowski, September 1999.
[54] Energy Information Administration, "U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves," 2001 Annual Report.

In contrast, there are only 183 trillion cubic feet of natural gas in proved reserves.[55] This amounts to only about nine times the 2001 annual production level. This is an overly conservative estimate of the amount of natural gas likely to be available in the future.

The U.S. has about 2 to 6 percent of the world's natural gas reserves and uses about 33 percent of the world's production annually. Currently the U.S. imports 16 percent of its natural gas but that is expected to increase as demand increases from 22 trillion cubic feet (TCF) to 35 TCF by 2025.[56]

Historically, market forces have helped the industry to discover and produce much more gas than the experts had originally thought was available. To wit, the American Gas Association reports that its Potential Gas Committee's 1998 estimate of the amount of gas available in the U.S. was approximately 4 percent higher than its 1990 estimate, even though a substantial amount of the gas supply had been consumed over the intervening period.[57] This suggests that even though large volumes of natural gas continue to be consumed, the available resource base may be expanding, not declining as gas prices move higher. Over the long-term, however, existing production areas may not be able to supply the increases in demand. In that case, gas would need to be brought to market from other areas. Examples include importing LNG, off-shore eastern Canada, the Mackenzie Delta, Alaska, and the Rocky Mountains.

The support for the concept of an increasing supply of gas is founded in part on the fact that currently uneconomic gas reserves may become economically attractive even if there is no technological improvement in natural gas production. The amount of economically recoverable gas interacts dynamically with the price of natural gas. This interaction makes it very unlikely that the country would ever "run out of gas." The more likely scenario is that if supplies begin to dwindle without an accompanying reduction in demand, the price of natural gas would rise.

Under those circumstances natural gas production would increase as natural gas supplies that were formerly too expensive to extract would then become economically attractive. At the same time, the higher prices would tend to have a moderating impact on demand. Thus, the price mechanism would simultaneously tend to increase supplies and decrease demand, thereby returning the natural gas market to balance. It is not surprising to find therefore, that with the current high natural gas prices there could be more economically recoverable supplies of gas than there were 10 years ago.[58]

The impacts of market adjustments that bring on the additional supplies are felt by consumers. The resulting equilibrium price that expands the resource base could be significantly higher than it was prior to the adjustment. So the real threat, in terms of reliability of supplies, is not that we will run out of natural gas, but rather that we might run out of inexpensive natural gas.

Holding all else equal, the pace of escalation in natural gas prices would likely be accelerated if natural gas remains the fuel of choice for new electric power plants. By the year 2001, the use of natural gas by electric generators had already approached the level of consumption from the commercial (non-industrial) sector. There appears to have been a major revision to the EIA consumption data between the time the draft EIS

---

[55] EIA defines proved reserves to be volumes of natural gas that geological and engineering data indicate with reasonable certainty appear to be recoverable from known reservoirs under existing economic and operating conditions.
[56] EnerFax Daily 2/26/03
[57] American Gas Association, *Fueling the Future: Natural Gas and New Technologies for a Cleaner 21st Century*, 2001.
[58] At the time that this section was drafted, spot natural gas prices were in excess of $6.00 per million Btu.

was prepared and the final EIS was written. When the draft EIS was written, the latest data available was the 2001 data that showed that natural gas use by the electric utilities amounted to 14 percent of the total useage. The new data reported for 2002 show that the figure has almost doubled to 27 percent.[59] In addition natural gas usage in the Industrial sector decreased in the last two years and it is not clear if the decrease was due to a softening economy or demand destruction due to higher prices. PSC staff has not yet had an opportunity to investigate the basis for these dramatic changes.

Table 5-1 Natural gas consumption by sector--2001 and 2002 (billion cubic feet per year)

2001 Data		
Sector	**Annual Consumption**	**Percent of Total**
Industrial	8,656	45%
Residential	4,809	25%
Commercial	3,037	16%
Electric utilities	2,686	14%
2002 Data		
Industrial	7,123	34%
Residential	4,915	24%
Commercial	3,147	15%
Electric utilities	5,553	27%

While the EIA data suggests that natural gas use by electric utilities is rapidly increasing, based on the orders placed for new turbines, the pace of adding natural gas-fired electrical generating capacity has slowed considerably in recent times. Figure 5-1 shows the delivered orders for gas turbines reported by General Electric over several years.[60] (The turbines are key components of natural gas-fired generating facilities.) This suggests that any upward pressure on natural gas prices due to new natural gas-fired generators may be less than had been anticipated several years ago.

Another fact that has bearing on the availability of natural gas for power generation projects is the overall demand for natural gas. The demand for natural gas in the U.S. actually peaked in 1973.[61] By 1986 the country was using 25 percent less natural gas than it did 13 years earlier. This is shown in Figure 5-2.

[59] Source: US Energy Information Administration
[60] Source: Jacqueline Doherty, "Turning on the Lights," *Barron's*, February 22, 2003.
[61] Source: US Energy Information Administration.

Figure 5-1 General Electric's gas turbine shipments by year

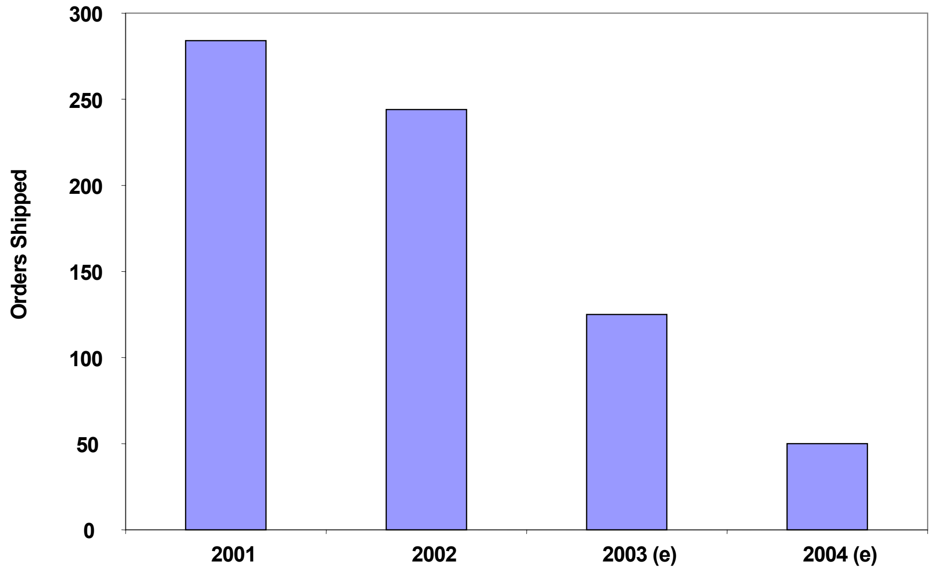
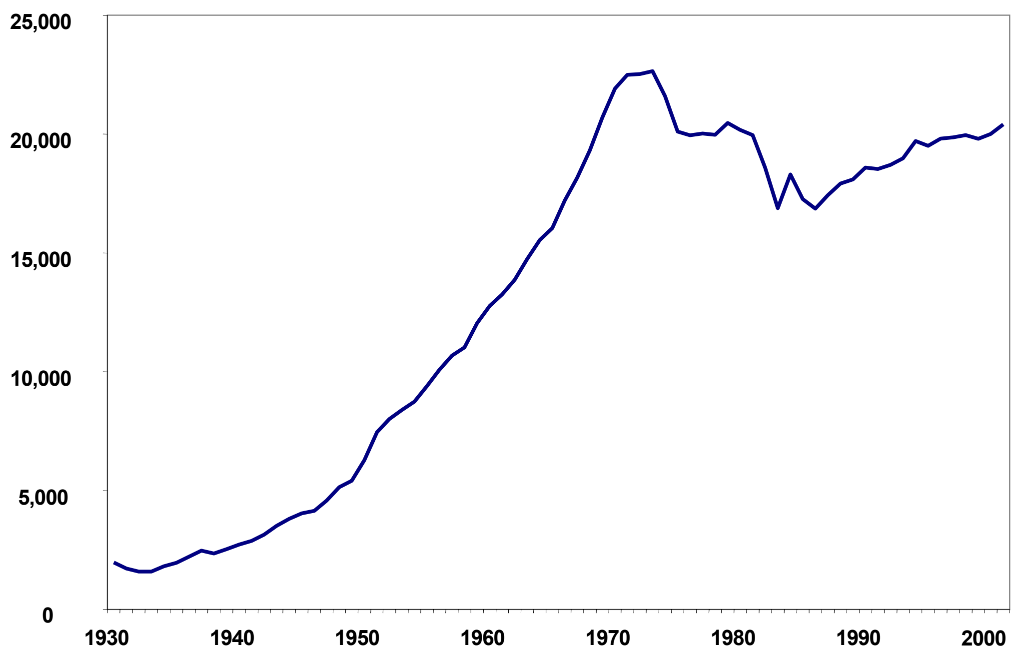


Figure 5-2 Marketed production of natural gas in the U.S. from 1930-2001

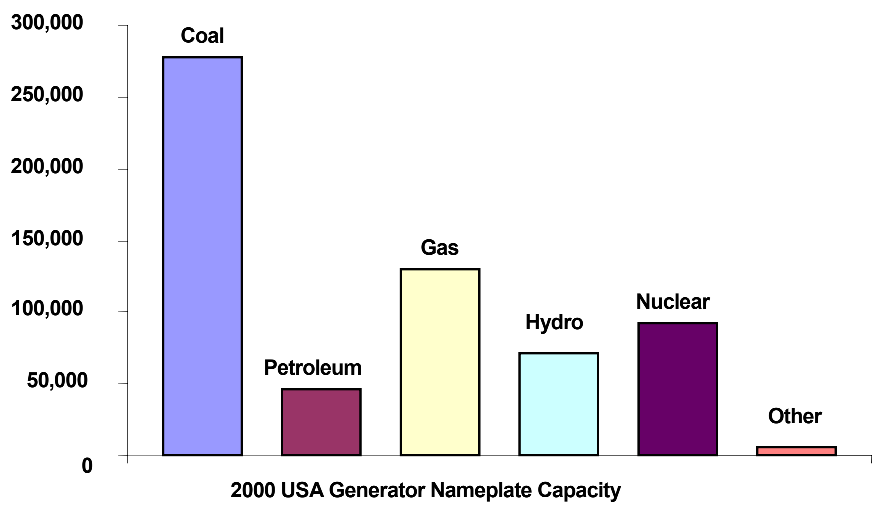


The demand for natural gas reversed its trend in the mid-eighties, although the subsequent growth rate has been slow. Over the past 15 years, natural gas demand has increased by a little more than one percent per year.

With the generally slow growth rate in natural gas demand and the apparent slowing in the pace of natural-gas-fired electrical generation, technological advance and technological innovation could allow for the development of additional supplies to keep pace with the demand for natural gas.[62] In fact, if new ways of drilling for gas are invented, or if news means of finding currently undiscovered gas supplies are developed and implemented, it may be possible to have an expanding resource base at lower prices than those experienced today. Another factor that could increase supplies and decrease prices is the development of natural gas in areas where natural gas production is currently not permitted. This would include Federal lands such as in national parks or in Alaska. Doing so, however, could have substantial environmental impacts that may preclude that option from being allowed.

In 2001 and 2002, over 90,000 MW of generation using natural gas as a primary fuel was installed nationwide. Through 2011, it is estimated that $35 billion in gas infrastructure nationwide will be required.[63] This has resulted in a large shift in the electric generation capabilities as shown in Figures 5-3 and 5-4.

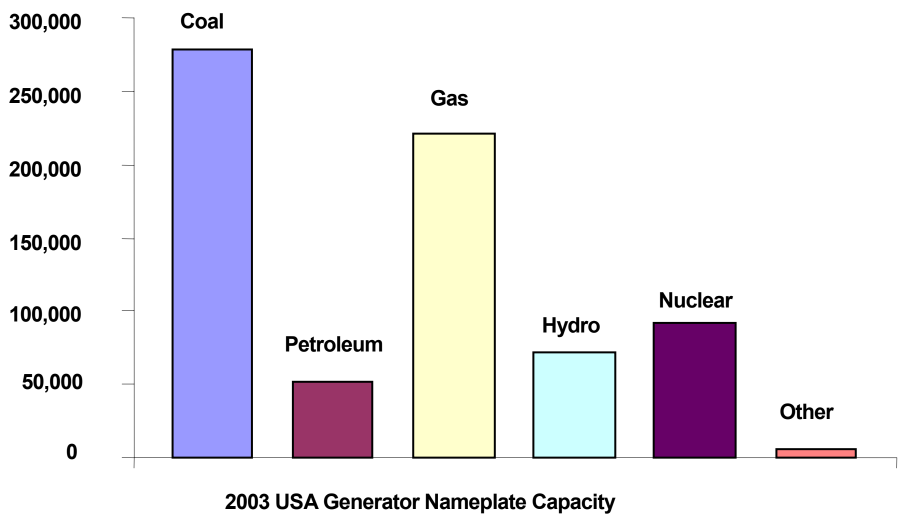
Figure 5-3 U.S. generating capacity in 2000



The addition of 90,000 MW of natural gas capacity in 2001 and 2002 to the existing 130,000 MW will add significantly to the gas consumption used for electric generation. According to EIA, the 1999 demand was 21.4 trillion cubic feet (21,400 billion cubic feet). Gas consumption for electrical generation represented 16 percent or 3,424 billion cubic feet of this total. The EIA estimates for overall demand for natural gas are estimated to increase only 2.3 percent per year.

[62] Technological advance refers to the invention of new technologies. Technological innovation refers to the use of existing technologies that had previously been invented, but that previously had not been used in practice.
[63] PTF Volum 1 Enclosure 1.0, Sec 7.0

Figure 5-4 U.S. generating capacity in 2003



No estimates for the expected capacity factors for this new generation are provided with the EIA data. One could assume that a 70 percent increase in nationwide generation would translate into a 70 percent increase in gas usage for electrical generation. If this is true, total gas consumption nationwide would increase by over 10 percent.

Natural gas production: short-term analysis

The amount of natural gas as a resource base is not, however, the controlling factor as to the availability of natural gas in the short run.[64] There can be a large basin of natural gas that is not developed; i.e., it has no operating drilling rigs to extract the gas. This gas cannot reach consumers. The high prices experienced in recent times appear to be heavily related to a failure of the natural gas producers to expand their operations over time.[65]

The productive capacity of the domestic natural gas industry is often summarized by a term referred to as the rig count, which is simply a count of the number of rigs actively withdrawing natural gas. The rig count has been quite volatile in the past decade and is in part responsible for the volatility of natural prices. For example, Baker Hughes[66] reported that in January 1999 there were 587 drilling rigs in operation in the U.S. This was 41 percent fewer rigs than were in operation a year earlier. Two years later (January 2001), the count had increased by 44 percent over the January 1999 level to 1,118 rigs. As of January 2003, the count has declined to 854 rigs, which amounts to a 24 percent reduction in the count over the past two years.

The short-run capacity to deliver natural gas tends to rise and fall directly with changes in the rig count. It is not so much the absolute level of the rig count that matters most, but rather the rig count relative to the level of demand. When the number of operating rigs is not sufficient to keep up with demand, two things

---

64 “Short-run” in this context is a period of no more than 18 months.
65 Russell Gold and Rebecca Smith, “Effects of Gas Shortage Rip Through Economy,” *Wall Street Journal*, February 28, 2003.
66 The Baker Hughes Rig Count is often used as the standard measure of the rig count in the natural gas industry.

happen: (1) interruptible customers do not receive natural gas; (2) natural gas prices rise; and (3) demand is reduced. So during these situations for the generator using natural gas, supplies might be available at high cost, or under certain conditions might not be available at all.

Natural gas transmission

The preceding discussion suggested that under certain circumstances natural gas might not be available to electric generators. This is almost a certainty if the generator relies on interruptible interstate transmission capacity to ship its natural gas from the production area in the southern U.S. to Wisconsin. Some interruptions may occur even if the generator has a contract for firm transmission, although the frequency of such interruptions would be much lower than that experienced by customers who rely on interruptible transportation.

Interruptible transportation rates for interstate pipelines are set at a fraction of the firm rate. That deep discount in the rate reflects the quality of service obtained. With the exception of very warm winters, interruptible customers can count on the fact that service will be unavailable on one or more days of the year. The pipeline does not expand its capacity when interruptible customers are added to its system. The interruptible customers essentially use any extra space available. On peak winter days there is not likely to be such extra space and the interruptible customers are often forced to stop taking natural gas on those days.

A generator customer that relies on interruptible interstate transmission capacity is by definition not going to be reliable during the coldest winter periods. Such an arrangement is reasonable if the generator is a peaking plant that will be used only during the electric utilities' summer peak periods. If, on the other hand, the plant is expected to be available year-round and the generator relies on interruptible transmission capacity to ship its natural gas to Wisconsin, a potentially difficult situation is very likely to occur. Under these conditions, unless the generator has dual-fuel capability, it will have to cease operation at a time when the electric system is relying on its output.

The Commission faces a potential problem as it relates to merchant power plant providers and knowing how or if these plants will affect overall system reliability. The supply procurement decisions are not always revealed when a merchant plant owner makes a proposal to provide electric capacity. For a merchant plant that is a base load or intermediate load facility, or if the facility is to be available as a peaking unit year-round, the interstate natural gas transmission capacity must be firm if electric reliability is to be maintained. Contracting for interruptible natural gas transmission capacity would be reasonable under these circumstances, only if back-up fuel can be used to power the generator.

That option would be acceptable, however, only if the merchant plant owner maintained adequate supplies of alternative fuel that could be used during periods of natural gas interruptions. During extremely cold weather, interruptions of the natural gas system could last for three days or more. For a dual-fueled 500 MW base load unit, the oil storage capacity would have to be quite large to assure that the plant could continue to operate. Relying on oil service companies to provide back-up fuel when natural gas facilities are interrupted may not be reliable. During periods of cold weather, many industrial customers also must switch to oil as their natural gas service is interrupted. This creates a dramatic increase in the demand for oil in a short time. If the oil service companies do not have the capacity to deliver to all of their customers, a portion of the demand for the generator may go unmet. On-site storage of several days of supplies of alternative fuel reduces the risk of this occurring.

If a merchant plant provider does not reveal the specific arrangements that it has made to meet its natural gas operations, it should be presumed to be of low reliability. Absent a showing that the plant will be available when needed, the Commission could reasonably assume that the plant is interruptible.

Contract provisions between the merchant plant and an electric utility that call for liquidated damages for failure to deliver the needed electricity are not a substitute for physical reliability. While such damage clauses are a necessary complement to such contracts, the only way to obtain the maximum assurance of the plant's reliability is to examine the underlying supply contracts. Payments of millions of dollars of liquidated damages may not compensate the state of Wisconsin for the harm caused by a lack of electrical energy at a critical time.

Even firm interstate pipeline capacity, however, is not a fail-safe alternative. There is always the possibility of *force majeure* type events (examples include war, an Act of God, etc.) that could prevent natural gas from flowing. These situations can affect all fuel types including natural gas, oil, and coal. With natural gas, however, there is an additional concern that may cause reliability concerns. Electric generators that use natural gas as the input fuel generally must receive natural gas at a delivery pressure of about 450 psig or higher. Local distribution utilities can generally maintain reliable service at lower pressures. The first sign of delivery problems on the interstate pipeline system is a drop in delivery pressure. This means that even if capacity arrangements are firm, generators could see problems before the local distribution utilities do when pressure problems occur. Thus an electrical generator with firm interstate pipeline capacity may be less reliable than a local distribution company (LDC) with the same service.

Pressure problems on the pipelines are more than a hypothetical concern. For example, on and around January 23, 2003 ANR Pipeline, the major provider of interstate pipeline capacity to the state, had difficulty maintaining pressure on its system.[67] The specifics of the situation, including the impact on natural-gas-fired power generators, are being investigated at this time.

If a large number of gas-fired generators want to obtain firm capacity on interstate pipelines, the pipelines serving the state may have to expand, or new pipelines may have to be built. The recently-constructed Guardian Pipeline is such an example. It brings an additional 750 million cubic feet per day of capacity to the state, some of which could be used to serve natural-gas-fired electric generators. On the surface, that represents about a 30 percent increase in the net capacity serving Wisconsin.[68]

That figure likely overstates the capacity increase for the state. As customers switch to contracts with Guardian, they temporarily strand capacity on other pipelines. The other pipelines have likely sold this stranded capacity formerly used to serve Wisconsin to customers in other Midwest states. So there is not likely to be a glut of pipeline capacity serving the state. That means that if large-scale natural-gas-fired generators are to be built in Wisconsin, substantial expansion of the interstate pipeline system serving the state may be necessary.

---

[67] February 6, 2003, letter from David J. Kyto (Wisconsin Public Service Corporation) to Robert Bauer (Public Service Commission).
[68] EIA reported that the net pipeline capacity serving Wisconsin in 2001 was approximately 2,500 million cubic feet/day. See James Tobin, *Natural Gas Transportation—Infrastructure Issues and Operational Trends*, Energy Information Administration, October 2001.

Natural gas distribution

In assessing the reliability of natural-gas-fired electrical generators that take service from a LDC rather than directly from a natural gas transmission pipeline, one must examine operational history of the LDC's distribution system. Like the pipelines, some gas utilities offer firm and interruptible distribution service. The reliability of service during the winter is diminished to some extent when the customer elects interruptible distribution service. The degradation in service quality is not as great, however, on the distribution system as it is on the interstate pipelines. The only LDC in Wisconsin that has interrupted its customers because of distribution constraints in recent years is Wisconsin Gas Company. In fact, distribution-related interruptions on the other utilities have been so rare that some utilities no longer offer interruptible distribution service. (Interruptible customers were essentially receiving firm service at discounted rates.)

There is another reliability issue that needs to be addressed for power generators on an LDC's distribution system. Even firm service is not absolutely guaranteed. For example, if an LDC's major distribution main is accidentally damaged during construction, large customers including electrical generators, would be among the first to be interrupted. The utility would attempt to flow gas to the customers that are at the greatest risk, which on a cold winter day would be residential customers. This type of interruption is rare, but the possibility does exist.

Natural gas reliability as a function of plant operation

Unlike a coal-fired utility that maintains weeks or months of fuel supplies at its site, it is generally not cost-effective for a generator to store natural gas on its site. So while a coal-fired facility is largely unaffected by the derailment of a unit train transporting coal to its facility, an interruption in the flow of natural gas to a gas-fired generator is likely to cause a problem. The situation is less severe if the generator can rely on alternative fuel. Gas-only plants would have no alternative but to cease operations if the flow of natural gas is interrupted.

Natural gas reliability: conclusion

In terms of the supply of the natural gas resource, rather than running out of gas generators are more likely to be faced with pricing problems. Natural gas will generally be available from supply basins if the generator is willing to pay for it. Reliability is more likely to be a concern on the interstate pipeline system if generators purchase interruptible capacity or if pressure problems occur on the pipelines. Reliability can also be impaired on the LDC distribution system, although problems are likely to occur less frequently there than they are on the transmission pipelines.

Solely in terms of reliable fuel supplies, the inability of generator owners to store natural gas on-site means that any interruption in the flow of gas can present major operational problems for the generator. This decreases the overall reliability of natural-gas-fired units relative to plants fired by coal. Whether natural-gas-fired plants are less reliable than coal plants when all relevant factors are considered is beyond the scope of this analysis.

The volatility of natural gas was especially noticeable this winter as winter returned to more normal colder temperatures, gas fired generation increased its share of natural gas needs, Canada was less able to import, and the US production fell from previous levels. Concern is developing about the adequacy of previous predictions and the availability of gas in the future.[69]

Economic Issues

As discussed earlier in Chapter 3, natural gas prices are extremely volatile. That means that the cost of electricity generated by burning natural gas will also be quite volatile. To the extent that these costs are passed on to consumers via fuel cost adjustments, electricity prices would become more volatile.

Volatility is not desirable for consumers. Volatile energy bills make budgeting more difficult. That affects residential, business, and governmental consumers. The use of natural gas to produce electric power will exacerbate problems currently faced by retail natural gas consumers because electric bills will tend to increase at the same time that natural gas bills increase. Put another way, using natural gas to fire electrical generators provides no diversification from natural gas price spikes. Rather it magnifies the impact of those spikes.

Alternatively, when comparing the capital costs of natural gas generation versus coal-fired generation, the capital construction costs for gas-fired plants are much more consistent, predictable, and significantly lower than those associated with coal-based facilities.

For instance, in the Port Washington CPCN case, the first 545 MW combined-cycle natural gas-fired generating unit is expected to cost $309.6 million in 2001 dollars. This is in contrast to the expected capital cost of $721 million in 2003 dollars for 515 MW from the first SCPC unit. Both units are of nearly equal size in generation output to be used by the utility, but the capital cost of the coal facility is more than double that of the gas-fired project. In addition, in the Port Washington CPCN case, the facility lease has a "hold to" cost feature, meaning that any cost overruns will not be passed on to ratepayers. The fact that a coal facility's capital cost is at least double that of a gas-fired generation facility and that any cost overruns in constructing the coal facilities could be passed on to ratepayers means that choosing a coal facility carries its own significant economic risks that must be weighed against price spikes and supply risks associated with choosing a gas-fired facility. However, in its May 2003 filing, WEPG limited the extent of any cost overruns to 10 percent. This will be a key issue in this case.

The following table displays fuel diversity mix by electric energy generation in the US, Wisconsin and surrounding states.

Table 5-2 Electric power industry generation - percentage of MWH generated by different fuel types in 1999

State	Coal	Nuclear	Gas	Hydro	Other
Illinois	45%	50%	4%	0%	1%
Iowa	85%	9%	1%	2%	3%
Minnesota	62%	27%	2%	2%	7%
Wisconsin	70%	20%	3%	3%	4%
US	51%	20%	16%	9%	4%
WEPCO (2001)	68%	27%	3%	0%	2%

* Source: EIA 1999 State Electricity Profiles and Figure 3-4 of the final EIS.

[69] Effects of Gas Shortage Rip Through Economy: Wall Street Journal , February 28, 2003

This table shows that Wisconsin and WEPCO rely on more coal-fired generation as an electric energy source than the US, Minnesota, and Illinois. Only Iowa uses proportionately more coal-fired electric generation. This table also shows the importance of nuclear generation. That is, Illinois uses less baseload coal-fired generation due to its sizeable use of nuclear power.
On a forward-going basis, given that the coal generation at Port Washington will be retired, if Oak Creek Units 5 and 6 are retired and only the SCPC units at ERGS are constructed, WEPCO's percentage share of electric generation in Table 5-2 may only moderately increase for the period after 2012.

Environmental Issues

Although much of the previous discussion focusing on fuel prices and volatility may appear to favor use of coal, a general environmental comparison of natural gas versus coal generation draws attention to other factors that should be considered in making a choice for future baseload generation capacity. The following discussion focuses on some of the basic environmental differences between these fuel choices.

Coal mining and transport

The use of coal as a fuel supports the coal mining industry, which has grown over the last several decades directly because of the nation's increased need for electricity. According to the U.S. Department of Energy, Energy Information Administration (EIA), in 1949, 84 out of a total of 483.2 million short tons of coal (approximately 17 percent) were purchased by electric utility plants. However in 2001, 948 out of a total of 1060.3 million short tons (approximately 89 percent) of coal were purchased by electric plants, showing an increase in the amount of coal mined and a significant increase in the percentage of coal mined for coal-fired electric power plants.

The coal mining industry is responsible for many severe environmental impacts. By necessity, surface land is disturbed in the process of mining coal. The actual coal mine facility can disturb a footprint of a few acres for underground mining operations or tens of square miles for a surface mining operation. However impacts from coal wastes, road building activities, subsidence, acid mine drainage, groundwater contamination, and other natural resource impacts can also have wide ranging effects, well beyond the boundaries of the surface disturbance of the coal mine.

To grasp the impact coal mining has had on the environment, one can examine the statistics for Pennsylvania, the fourth largest coal-producing state in the U.S. and the source of the coal to be used in the ERGS facilities. Pennsylvania currently has about 2.6 billion cubic yards of coal refuse which is generally unsuitable for plant growth and a potential source of acid mine drainage. According to the Federal Office of Surface Mining, Pennsylvania ranks first in the nation in the total estimated cost (over $15 billion) of environmental cleanup needed for the past mining of coal. In recent years, Pennsylvania spending for mine reclamation has averaged $21 million annually. Despite many regulations written to protect environmental resources from adverse effects associated with new mines, impacts as a result of newer technologies and environmental accidents continue to occur.

In addition to environmental concerns, as a heavy industry, underground coal mining, including longwall mining, has many safety concerns for those individuals engaged in the mining work.[70] Accidents related to electrical work, hydraulics, fire, or flood can occur. There is a need to monitor coal dust production and exposures to arsenic, cadmium, lead, mercury, and other components in the coal. While much progress has been made in reducing respirable dust levels in mines, black lung (also known as coal workers' pneumoconiosis and silicosis) continues to occur among coal miners. Black lung can devastate a miner's quality of life, affect a miner's family, and lead to premature death.

ERGS has proposed the use of Pittsburgh #8 bituminous coal with the Blacksville Mine as a typical coal supply. The Blacksville Mine uses the longwall method, a type of underground, continuous, highly mechanized mining method. Whereas the permanent changes on the landscape are clearly visible from surface mining operations, underground mining also has wide-reaching environmental impacts as well. Surface mining affects many acres by eliminating surface vegetation, permanently and drastically altering soil and subsurface geological structure, and disrupting surface and subsurface hydrologic regimes. Underground mining due to subsidence can have the same set of impacts.

By its very nature, underground coal mining entails a risk of surface subsidence as gravity induces the downward movement of the overlying rock strata to fill the void left where coal has been removed. Longwall mining, by contrast with more traditional methods of underground coal removal, induces deliberate, uneven subsidence of the land surface relatively quickly after mining. This subsidence affects surface water hydrology, altering soil and subsurface structure, and species habitat. Subsidence and fracturing can also induce the acidic water associated with overlying coal seams to enter drinking water wells and streams.

Coal is transported primarily by train. As the utility industry need for coal has increased, the amount of coal transported by train has increased. The EIA reported that the quantity of contract coal shipped by rail to electric utilities rose from 269.6 to 366.2 million short tons from 1988 to 1997, an increase of 36 percent. The average distance contract coal has been shipped by rail rose from 640 miles in 1988 to 793 miles in 1997. The increase of coal trains and train traffic in turn has increased the amount of noise and coal dust blowing off trains. Air pollution has also increased from train operation, especially nitrous oxides, carbon monoxide, and sulfur dioxide. CO2 production is discussed in Chapter 7. If a carbon tax is imposed, the additional cost could be dramatic. A carbon tax is one of the sensitivities discussed in the EGEAS modeling in Chapter 4.

Natural gas extraction and transport

Natural gas is extracted either through "free-flowing wells" because of natural pressure underground or by some type of pumping system. After the natural gas is extracted, it is treated at gas plants to remove impurities such as hydrogen sulfide, helium, carbon dioxide, hydrocarbons, and moisture. Pipelines transport the natural gas from the gas plants to power plants. Construction of major gas transmission pipelines and the numerous distribution laterals can cause substantial environmental effects, depending on the terrain, land use, and land cover.

[70] Information on black lung and mine safety can be found in the web site of the Mine Safety and Health Administration of the U. S. Department of Labor -- http://www.msha.gov/

The extraction of natural gas and the construction of natural gas power plants can destroy natural habitat for animals and plants. Possible land resource impacts include erosion, loss of soil productivity, and landslides. However, natural gas extraction is a much less disruptive installation than a typical coal mine. A field of production wells often can share the landscape with fields of corn and soybeans, though the oil and natural gas extraction process does result in outputs of drilling mud, drill cuttings, and well maintenance products. Disposal of these materials, as well as materials resulting from equipment cleaning, have the potential to create water quality impacts if not carefully managed.

Resource needs and impacts

Water

Coal-burning technologies have major resource needs related to water, land, and solid waste disposal compared to natural gas-fired combined-cycle plants or simple combustion turbines. The following discussion describes some of these needs and the associated impacts.

The two SCPC units of the ERGS project (about 1,230 MW) would require about 1,400 million gallons per day (mgd) of water for purposes of cooling, ash removal, demineralization processes and make-up water. Approximately 1.7 mgd would be "consumed" by various processes or evaporated, thus discharging approximately the same amount of water as was initially withdrawn. Release of this large quantity of heated water into a surface water body can result in major environmental impacts and substantial changes due to thermal pollution. These impacts could vary depending on the ambient water temperature, the physical characteristics of the water body (i.e. flow rate, water depth, etc.), and the time of year.

Alternatively, a similarly-sized natural gas-fired combined-cycle plant (1,180 MW) would require about 7.0 mgd for operation. However, the majority of this water (about 5.0 mgd) would be consumed during plant operation or evaporated from the plant's cooling towers returning less than 2.0 mgd to the river or lake from which it was drawn.

Thus, with respect to the ERGS and an alternative gas-fired generation plant, there is a trade-off between the potential thermal pollution effects and a water consumption concern. (Note: Coal plants can also utilitize cooling tower technologies rather than once-through cooling systems as proposed for the ERGS. In coal plants that have cooling towers, the quantity of water evaporated is much greater than for a natural gas-fired plant.)

Solid waste

The need for ash landfills is always a consideration when proposing to build new coal-generation. The two SCPC units of the ERGS facilities are expected to produce 206, 300 tons of fly ash and 51,600 tons of bottom ash per year. New landfills are very difficult to site and must be maintained to avoid impacts due to surface runoff or leaching. The potential to reburn some amount of landfilled ash and the developing beneficial re-use market for ash and other coal-based generation by-products will help to reduce the need for new landfills and slow the rate at which existing landfills reach capacity.

Solid wastes produced by natural gas-fired facilities are primarily limited to sludge cakes resulting from the pre-treatment of raw surface water for use in the plant.

Land

The amount of land required for a natural gas-combined cycle plant is much less than that needed to accommodate a similarly sized (MW capacity basis) coal-burning generator. The auxiliary facilities, such as rail tracks, coal silos and coal handling equipment, coal piles, and ash landfills result in a much larger "footprint" of disturbed land. In addition, the noise, fugitive dust, and safety issues create a need for a substantial buffer area around the plant facilities. As in the case of the existing OCPP property however, if managed properly, this buffer land can preserve special resources and habitat functions.

Air emissions

The air emissions profile for a coal-fired generator is quite different from that of a natural gas-fired combined-cycle plant. Coal and limestone are the mercury sources for the ERGS facility, which is expected to emit about 300 lbs. of mercury per year. Mercury is not a pollutant emitted by natural gas combustion.

In addition, SO_2 (3-hr and 24-hr) and particulate matter, specifically PM_{10} (24-hr) are emitted in much higher concentrations from coal-fired plants than from natural gas facilities. These higher concentrations occur even though the best available control technologies have been implemented to reduce emissions. The proposed ERGS SCPC units include a flue gas desulfurization system (FGD) and the IGCC plant would have a sulfur recovery unit (SRU) to minimize the amount of sulfur emitted.

CO_2 emissions

In data response 1-SUP-178 dated March 4, 2002 WEPCO indicated to PSC staff that CO_2 emissions from 600 MW of coal would be about 3,500,000 tons per year. A DNR analsyis completed since the issuance of the draft EIS indicates that CO_2 emissions up to 4,450,000 tons per year could occur. This is in contrast to 450,000 tons per year for a 500 MW natural gas-fired combined-cycle plant. Presently, CO2 is not a regulated emission. Due to concerns over climate change, CO2 emissions could come under closer regulation in the future. To the extent such emissions did come under supervision, ratepayers in Wisconsin could be faced with higher compliance costs under an expansion plan utilizing more coal-fired generation than natural gas.

Chapter Summary

In summary, the primary points raised in this chapter are:

- The supply of coal is plentiful.
- Gas use is increasing nationwide with the potential to increase dramatically at the state level, depending on the level of merchant plant development.
- It is unlikely natural gas growth can be sustained without increasing price volatility and more infrastructure improvements such as gas wells, interstate pipelines, intrastate pipelines, and liquid natural gas facilities.
- .Reliability issues with electric generation may increase as the percentage of natural gas generation increases.
- Natural gas prices have been volatile. Increased reliance on generation from natural gas-fired power plants could lead to more volatile electricity prices for consumers.

- In selecting the appropriate electricity supply resources, the Commission must balance the higher marginal energy cost, price spike potential, and supply risks associated with natural gas-fired facilities versus the economic risks of choosing a coal facility in which a coal facility's capital cost is at least double that of a gas-fired generation facility for a similar amount of energy output and that cost overruns in constructing the coal facilities can be passed on in part to ratepayers.
- If a carbon tax is imposed, coal plants could be dramatically affected to the ratepayers' detriment.
- Coal can be stored on-site in large quantities providing a fuel inventory that can last longer than natural gas.
- Coal-burning power plants typically emit higher concentrations of SO_2 , Hg, and certain particulates than natural gas-fired facilities with a similar capacity.
- Disposal of solid waste, including ash and other by-products, is an environmental issue for coal facilities, but not natural gas plants.
- The amount of land needed for placement of auxiliary facilities and buffer area is much greater for coal plants than for natural gas-fired generators.
- Coal-based facilities have major cooling water requirements. Although this may not be a consumptive water use, it can result in thermal pollution concerns.
- Natural gas-fired combined-cycle facilities often evaporate a large percentage of the intake water, causing consumptive water use concerns.
- Coal mining is generally more disruptive to the environment than natural gas drilling. Also, health problems associated with underground coal mining, including black lung disease, continue to occur despite federal efforts to improve conditions for miners.